

Washington University in St. Louis
Washington University Open Scholarship

All Theses and Dissertations (ETDs)

Summer 8-1-2012

Economic Prospects for Advanced Combustion Technologies Suited for Climate Change Mitigation

Craig Bryan Jacobson
Washington University in St. Louis

Follow this and additional works at: <https://openscholarship.wustl.edu/etd>



Part of the [Engineering Commons](#)

Recommended Citation

Jacobson, Craig Bryan, "Economic Prospects for Advanced Combustion Technologies Suited for Climate Change Mitigation" (2012).
All Theses and Dissertations (ETDs). 1029.
<https://openscholarship.wustl.edu/etd/1029>

This Thesis is brought to you for free and open access by Washington University Open Scholarship. It has been accepted for inclusion in All Theses and Dissertations (ETDs) by an authorized administrator of Washington University Open Scholarship. For more information, please contact digital@wumail.wustl.edu.

WASHINGTON UNIVERSITY IN ST. LOUIS
School of Engineering and Applied Science
Department of Energy, Environmental & Chemical Engineering

Thesis Examination Committee:
Pratim Biswas, Chair
Brent Williams
Yinjie Tang

ECONOMIC PROSPECTS FOR ADVANCED COMBUSTION TECHNOLOGIES
SUITED FOR CLIMATE CHANGE MITIGATION

by
Craig Bryan Jacobson

A thesis presented to the School of Engineering
of Washington University in partial fulfillment of the
requirements for the degree of

MASTER OF SCIENCE

August 2012
Saint Louis, Missouri

ABSTRACT OF THE THESIS

Economic Prospects for Advanced Combustion Technologies

Suited for Climate Change Mitigation

by

Craig Jacobson

Master of Science in Energy, Environmental & Chemical Engineering

Washington University in St. Louis, 2012

Research Advisor: Professor Pratim Biswas

Coal is projected to remain a significant portion of the global energy portfolio in the coming century. Concerns over accelerating climate change have spurred development of technologies aimed at reducing CO₂ emissions from coal-fired power plants through carbon capture and sequestration (CCS). Utilities considering expansion of baseload generation capacity face a myriad of uncertainties regarding the timing and scale of future carbon legislation. This study reports on an economic evaluation of various technologies for carbon capture, sequestration, and utilization.

Acknowledgments

I would like to acknowledge George Mues, Principle Engineer at Ameren Corporation, for his guidance in this work. Partial support from the Consortium for Clean Coal Utilization at Washington University in St. Louis and the McDonnell Academy Global Energy Environmental Partnership (MAGEEP) is gratefully acknowledged. Additionally, I'd like to offer my sincere gratitude to my family and friends who supported me throughout my graduate education.

A special thanks goes to the many graduate students and distinguished faculty within my department who have helped with knowledge, guidance, and spirited conversations surrounding this work.

Craig Jacobson

Washington University in St. Louis

August 2012

Dedicated to my Mom, who has always been with me, through thick and thin.

Dedicated to my Dad, who showed me the value of engineering.

Dedicated to my Brother, who satiated the grandchild requirement.

Dedicated to my Niece, Amaya and her baby sister, whom I love dearly.

Contents

Abstract	ii
Acknowledgments	iv
List of Tables	vi
List of Figures	vii
1 Economic Prospects for Advance Coal Combustion Technologies with Carbon Capture, Sequestration and Utilization	1
1.1 Introduction	1
1.2 Methodology	4
1.3 Technology Options for Coal Combustion with Carbon Capture and Storage ..	5
1.4 Simulation Plan	8
1.5 Results and Discussion	9
1.5.1 Economics of Carbon Capture Technologies	10
1.5.2 Carbon Tax Breakpoints for Greenfield Projects	15
1.5.3 Carbon Tax Breakpoints for Existing Power Plants	18
1.5.4 Economics of Carbon Capture and Utilization	19
1.5.5 Sensitivity to Coal Price - CCS Technologies	21
1.6 Conclusions	22
2 Techno-economic assessment of Advance Coal Combustion Technologies Suitable for Carbon Capture and Sequestration in India	24
2.1 Introduction	24
2.2 Methodology	26
2.3 Results and Discussion	27
2.4 Future Directions	27
Appendix A Biomass Power Plant in India	31
Appendix B Methods and Scripts	35
References	31
Vita	35

List of Tables

Table 1.1:	Financial assumptions used for U.S. analysis.....	5
Table 1.2:	Fuel Composition - Wyoming Powder River Basin	5
Table 1.3:	Simulation plan for economic analysis advanced combustion technologies for carbon capture and sequestration and/or utilization.....	9
Table 1.4:	Summary of results for four technologies. Fuel is PRB priced at \$8.75/ton as fired, all plants have a capacity factor of 75%.....	12
Table 2.1:	Financial assumptions used for India analysis	25
Table 2.2:	Fuel Composition - Indian Domestic Coal	26
Table 2.3:	Fuel Composition - Indonesian Imported Coal	26

List of Figures

Figure 1.1: Capital required for new 500 MW-net power plants. Required revenue is displayed above the plot for each technology. Capital expenses are separated into the following sections of operation: Black - Base plant equipment (such as boiler, steam turbines); Red - Environmental controls (SO _x , NO _x , PM, Hg); Green – Carbon capture & storage for Subcritical PC power plants:	13
Figure 1.2: Capital required for new 500 MW-net power plants. Required revenue is displayed above the plot for each technology. Capital expenses are separated into the following sections of operation: Black - Base plant equipment (such as boiler, steam turbines); Red - Environmental controls (SO _x , NO _x , PM, Hg); Green – Carbon capture & storage for Ultra-supercritical PC Power Plants:	14
Figure 1.3: Carbon tax breakpoint analysis for greenfield plants; Subcritical PC Plants with CCS - 500 MW-net: PC – Baseline; Amine – CCS; Oxy-coal – CCS; IGCC; IGCC - CCS	16
Figure 1.4: Carbon tax breakpoint analysis for greenfield plants; Ultra-supercritical PC Plants with CCS - 500 MW-net: PC – Baseline; Amine – CCS; Oxy-coal – CCS; IGCC; IGCC - CCS	17
Figure 1.5: Carbon tax breakpoint analysis for existing subcritical plants: Change in cost of electricity from CO ₂ Tax; Amine – RUL - 10; Amine – RUL - 20; Oxy – RUL - 10; Oxy – RUL - 20	19
Figure 1.6: Carbon tax breakpoint vs. revenue from CO ₂ utilization: Impacts on carbon tax breakpoints from revenue generated via CO ₂ utilization are shown with 90% CO ₂ capture efficiency and three utilization to sequestration ratios; 90% CCU 50% CCU and 40% CCS ; 10% CCU and 80% CCS	21
Figure 1.7: Coal price sensitivity – Sensitivity analysis of the capture technologies to increasing coal prices. PC – USC - Baseline; Oxy – USC - CCS; Amine – USC - CCS	22
Figure 2.1: Carbon trading value breakpoint analysis for greenfield plants: Sub – PC – Baseline; SC – PC; USC –PC; USC – Oxy-coal – CCS; USC – Amine – C C S : Pulverized Coal Plants with CCS – 600 MW-gross burning Indonesian Coal:	27
Figure 2.2: Carbon trading value breakpoint analysis for greenfield plants: Sub–PC–Baseline; SC–PC; USC–PC; USC – Oxy-coal – CCS; USC – Amine – CCS: Pulverized Coal Plants with CCS – 600 MW-gross burning Indian Coal:.....	28
Figure 2.3: Carbon trading value breakpoint analysis for greenfield plants: Indian Coal– USC- Oxy; Indonesian Coal – USC–Oxy; Indian Coal – Subcritical Baseline; Indonesian Coal – Subcritical – Oxy; Pulverized Coal Plants with CCS – 600 MW-gross	28
Figure 2.4: Carbon trading value breakpoint analysis for greenfield plants: Indian Coal – 50 USD – USC - Oxy; Indonesian Coal–83 USD – Ultra-supercritical – Oxy; Indian Coal – 50 USD – Subcritical Baseline; Indonesian Coal 83 USD – Subcritical Baseline; Indonesian Coal 76 USD – Subcritical Baseline: Pulverized Coal Plants with CCS – 600 MW-gross	29

Chapter 1

Economic Prospects for Advanced Coal Combustion Technologies with Carbon Capture, Sequestration and Utilization

1.1 Introduction

An increasing supply of energy will be required to meet economic development goals of many countries around the world. While the political debate over the relationship between rising atmospheric concentrations of CO₂ and global climate change lingers, increases in population and subsequent demand for electricity are almost certain. Pending major growth in generation capacity from nuclear power or renewable energy, coal will remain a significant component of the global energy portfolio in the 21st Century. Among fossil fuels, coal resources are considered to be abundant, energy dense, currently inexpensive, and widely distributed throughout the world. For countries with vast coal reserves (United States, India, and China), as well as for major importers of coal (Europe and East Asia), both economic drivers and the desire for secure, reliable energy ensure that coal will remain in widespread use for electricity generation in the foreseeable future. However, associated CO₂ emissions and other pollutants remain a concern (Biswas et. al, 2011).

The Intergovernmental Panel on Climate Change's (IPCC) 2007 report, Summary for Policymakers, indicates that continuous annual carbon emissions on the gigaton scale impact the global climate over multiple decades. Additionally, anthropogenic greenhouse gas (GHG) emissions are implicated in contributing to near-term warming trends. While carbon dioxide is one of several greenhouse gases, it

accounts for 63% of radiative forcing (21% stemming from coal) attributed to anthropogenic emissions (Sturm and McDonald, 2011). The IPCC target for atmospheric concentration of CO₂ of 450 parts per million (ppm) requires that emissions from coal utilization be mitigated (Sekar et al., 2007). Pending significant improvements in the economic viability of electricity generated via renewable resources (e.g. wind, solar), carbon capture and sequestration (CCS) appears to be one of few technologies enabling continued global economic development while limiting CO₂ emissions. Utilization of captured CO₂ for enhanced oil recovery and conversion to useful products are also being researched (Wang, 2011). CCS involves the capture, concentration, and storage of CO₂ in geologic formations. Successful carbon storage and sequestration was first achieved on a commercial scale in the Sleipner West gas field, located in the North Sea off the coast of Norway (Herzog, 2004). Currently, three primary technologies are commercially viable for CCS: pre-combustion via integrated gasification and combined cycle, post-combustion using amine-based sorbents, and oxy-combustion, where combustion takes place in an oxygen-rich environment yielding a high percentage of CO₂ in the flue gas.

As with other CCS technologies, oxy-coal combustion has yet to be demonstrated and deployed at full scale, leaving the burden of technical risk with utilities and vendors. During the past decade, oxy-coal technology has been researched heavily at the laboratory scale (Suriyawong, 2008), with subsequent pilot projects of increasing capacity (Wall et al., 2011). But the majority of large projects pertaining to energy infrastructure development have been directed towards integrated gasification and combined cycle projects. Recently, the U.S. Department of Energy (DOE, 2010) and the European Union (EUROPA, 2009) awarded utility scale demonstration projects for oxy-fuel power plants with CCS. FutureGen 2.0, the United States' second attempt at full-scale demonstration of CCS, is a proposed retrofit of an existing boiler unit in Meredosia, IL. The proposed plan calls for a 200 MW-gross (140 MW-net) oxy-coal plant capturing 90% of CO₂ emissions for storage in a nearby deep saline aquifer. Two additional utility scale oxy-fuel projects are also slated for completion before 2018: Jaenschwalde and Compostilla (Wall et al., 2011). Summit Power is constructing an integrated gasification and combined cycle (IGCC) power plant as part of the Texas Clean Energy Project. This IGCC plant will produce approximately 400MW gross, with

186 MW being devoted to the processing of profitable by-products on-site, and the remaining capacity provided to local consumers.

Coal-fired power plants in the United States have generated electricity for decades and account for just under 50% of electric capacity. The impact of decisions made in the 1930s concerning the characteristics of these power plants endures today. With more stringent regulations on emissions and potential carbon legislation expected in the future, utilities considering building new plants face a myriad of uncertainty regarding which technology is most economical (Patiño-Echeverri et al., 2007). In the face of these uncertainties, previous studies have focused on whether a utility would prefer pulverized coal (PC) or integrated gasification and combined cycle (IGCC) power plants (Bergerson and Lave, 2007; Descamps et al. 2008). Rigorous systems modeling within these studies simulate operating conditions of utility scale power-plants to provide compartmentalized performance estimates. Prior analyses note that without external incentives, utilities prefer PC plants owing to less inherent technical risk (Sekar et al. 2007). Comparative studies detailing economic performance of fossil fuel power plants with CCS have focused on PC plants with amine-based capture as well as IGCC and natural gas combined cycle (NGCC) power-plants with and without capture (Rubin et. al, 2007; Davison, 2007). Techno-economic analysis of carbon capture options indicates oxy-coal systems as potentially the most attractive option in the face of uncertain carbon legislation (Varagani et al., 2005). Such analyses have not incorporated economic impacts that profitable utilization of captured carbon might have on carbon tax breakpoints.

In this chapter, current economic estimates for advanced combustion technologies are presented and explored for parametric sensitivity. The objectives of this analysis are to: (1) compare capital expenditures and cost of electricity (COE) of oxy-coal technology to other coal combustion technologies suitable for carbon capture and sequestration for greenfield projects; (2) evaluate hypothetical carbon tax levels at which specific advanced coal technologies with CCS may be cost-effective for a greenfield project as well as for existing coal-fired power plants; (3) evaluate the impact of carbon dioxide re-use technologies on the economics of CCS; and (4) determine the technologies' sensitivity to coal price increase.

1.2 Methodology

Utility-scale demonstration plants incorporating CCS have not yet been built; therefore, this analysis is based on current best available engineering estimates. To incorporate the myriad of factors affecting the performance, emissions, and capital expenses associated with the operation of electric power plants, the Integrated Environmental Control Model (IECM) version 6.2.4. is used (Rubin et al., 2009). The IECM is a publicly available modeling tool that was developed by Carnegie Mellon University in conjunction with the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL). Over the past decade, the IECM has been modified to include various configurations for PC plants, IGCC, and most recently, oxy-coal systems incorporating transport and storage costs of carbon dioxide. Recent studies have validated performance characteristics of oxy-fuel systems generated in the IECM with Aspen Plus software (Khorshidi et al., 2011). Though the IECM has probabilistic capabilities for modeling uncertainty, a conventional deterministic analysis is used within for ease of comparison.

Power plants with similar electric output, approximately 500 MW-net, and burning the same fuel stock (Wyoming Powder River Basin coal, PRB), are modeled. Key parameters for the analysis are listed in Table 1.1 and Table 1.2. Primary base assumptions include: 75% capacity factor, 30 year plant life for greenfield projects, real bond interest rate of 5.83%, cost of PRB is \$8.75/ton as-fired. All values are in 2009 U.S. dollars excluding inflation to minimize the impact of financial assumptions. Results are also presented for existing plants with remaining useful lives of 10 and 20 years.

Capital and operating expenses, as well as projected costs of electricity are likely to differ in actual plants. The values provided within are based on best available engineering estimates. In comparing capital costs among the various technologies, subcritical PC plants without carbon capture offers the lowest cost alternative. For plants capturing 90% of CO₂ emissions, IGCC was the lowest cost alternative, followed by oxy-coal power plants and the highest cost using PC with amine sorbents for post-capture. Potential improvements to economic viability of CCS via current markets for CO₂ utilization are explored in this analysis.

Table 1.1: Financial Assumptions

Financial Assumptions	
Plant or Project Book Life (years)	30
Real Bond Interest Rate (%)	5.83
Real Preferred Stock Return (%)	5.34
Real Common Stock Return (%)	8.74
Percent Debt (%)	45
Percent Equity (Preferred Stock)(%)	10
Percent Equity (Common Stock)(%)	45
Inflation (%)	0
Federal Tax Rate(%)	34
State Tax Rate (%)	4.15
Property Tax Rate (%)	2
Investment Tax Credit (%)	0

Table 1.2: Fuel Composition – Wyoming Powder River Basin

Wyoming Powder River Basin	
Heating Value (Btu/lb)	8,340
Carbon (wt%)	48.18
Hydrogen (wt%)	3.31
Oxygen (wt%)	11.87
Chlorine (wt%)	0.01
Sulfur (wt%)	0.37
Nitrogen (wt%)	0.70
Ash (wt%)	5.32
Moisture (wt%)	30.24
Cost (wt%)	8.75

1.3 Technology Options for Coal Combustion with Carbon Capture and Storage

Energy in coal can be used for industrial processes in two ways: either via direct combustion, where coal is burned in a boiler, or gasification, where coal is partially combusted to generate synthesis gas. Pulverized coal power plants using direct combustion are the most common sources for electricity generation in the U.S and abroad. In the PC process, coal particles are combusted with air in a boiler to produce steam, which spins a turbine to generate electricity. To capture and store the resulting carbon dioxide emissions at lowest cost, a pure stream of CO₂ is required. The three

primary methods to capture CO₂ from PC plants are designated based on order in the combustion process: pre-combustion, post-combustion, or oxy-combustion capture.

Pre-combustion capture requires that carbon be removed from the fuel prior to combustion. This is accomplished through the gasification of coal, a process dating back to the 1920s that produces a valuable mixture of hydrogen and carbon monoxide (H₂ and CO) known as synthesis gas (syngas). Water vapor (steam) is mixed with coal at high temperatures to oxidize the coal to CO, CO₂, H₂ and water. The most common and commercially viable stage in the process is to remove CO₂ at high partial pressure via a physical absorption process from the hydrogen-rich fuel gas produced through water-gas shift reaction by shifting CO to CO₂, also known as the sour shift reaction. The syngas produced in gasification can be used in combustion as well as in the production of fine chemicals, offering marketable by-products. It may be used as a starting point to synthesize other chemicals or it could be used in cleaner power generation through combustion (Katzner, 2008).

A major challenge of post-combustion capture lies with dilute flue gas, approximately 14% of which is CO₂. In order to separate the CO₂ in preparation for compression and subsequent storage, the flue gas stream is typically passed through an alkyl-amine (amine) based scrubber. The absorbed CO₂ is then stripped via temperature increase, regenerating the amine solution. Several key parameters determine the technical and economic operation of this amine based CO₂ adsorption system including: flue gas flow rate, CO₂ concentration, CO₂ removal percentage, solvent flow rate, and energy requirements to regenerate the solvent (Kanniche et al., 2010).

Oxy-combustion systems, referred to as oxy-coal systems when specifying the feed stream, directly alter the combustion environment. Instead of combusting with air, coal is fired in a chamber with approximately 30% oxygen and 70% recycled flue gas to maintain temperatures within the allowable range by ensuring the proper stoichiometric ratio for coal and O₂. The resulting flue gas, after condensing the moisture and removing the sulfur compounds, is approximately 99% CO₂, eliminating the need for energy intensive post-combustion separation. Two types of oxy-coal systems are currently being considered: an oxy-coal boiler and oxy-coal combustion based gas turbine cycles. Oxy-coal combustion based gas turbine cycles, including chemical looping combustion systems and novel power cycles using CO₂ and water as working

fluids are still under development. However, oxy-coal boilers are ready for commercial scale testing and deployment (Wall et al., 2011).

While not yet commercially viable, chemical looping combustion is receiving considerable attention. Chemical looping combustion (CLC) is an alternative combustion process that has the potential to revolutionize combustion technology in the face of impending carbon emission regulations. CLC was developed in 1983 by Richter and Knoche originally intended to achieve higher levels of combustion efficiency. CLC makes use of an oxygen carrier, usually a metal oxide, to introduce oxygen to a hydrocarbon fuel source without direct contact with air, similar to oxy-fuel combustion. This process has yet to be implemented on a commercial scale due to a lack of research and development. Currently, there are no large-scale CLC plants in operation, but several pilot plants with capacities ranging from 10 to 300 kW. One of the key impediments for large scale operation lies in identifying an appropriate oxygen carrier (Abad, 2011). While this technology holds promise, it is currently not commercially viable and therefore outside of the scope of this analysis.

In order to effectively compare the various power-plant scenarios, a baseline PC plant was modeled for reference representing the current state-of-the-art PC plant with various environmental controls addressing NO_x, SO_x, PM, and Hg regulations. Included in the PC - baseline plant are in-furnace NO_x controls in a tangentially fired boiler, hot-side selective catalytic reduction (SCR), cold-side electrostatic precipitator (ESP) for particulates, and wet flue gas desulfurization (FGD) for SO_x control. All water and solids management systems are composed of a once-through cooling system with ash pond disposal. Fly ash is combined with the flue gas desulfurization wastes and, in some cases sold for use in cement or gypsum board for nominal profit, but in this analysis assumed to be disposed.

1.4 Simulation Plan

The simulation plan outlined in Table 1.3 provides the overall scheme of the analysis. Upon establishing baseline values for capital expenditure, cost of electricity, and CO₂ emissions for reference in simulation one, each technology is compared via three scenarios affecting the economics of operation: carbon tax on emissions, revenue from carbon utilization, and increases in coal price. Simulation two identifies what tax per ton of carbon emissions would provide an economic case for a utility to capture and store CO₂ today using a greenfield analysis. This crossover point is defined here as the carbon tax breakpoint. In simulation three, additional carbon tax breakpoints are identified for retrofit scenarios where new carbon-capture equipment is installed on plants with reduced remaining useful lives. Potential revenue streams from captured CO₂ were then explored for their effect on the carbon tax breakpoint and COE in simulation four. Finally, as recent studies propose that coal reserves may not be as abundant and readily obtainable as once thought, carbon capture technologies for PC plants were compared to determine their parametric sensitivity to coal price fluctuations in simulation five. (Heinberg and Fridley, 2010; Rutledge and Keith, 2011)

Table 1.3: Simulation plan for economic analysis of advanced combustion technologies for carbon capture and sequestration and/or utilization.

Simulation Number	Description	Results	Objective
1.	Capital expenditure estimations for various CCS technologies	Base Plant, Environmental Controls, Unit Cost of Electricity, CO ₂ emissions per MW per year (Figure 1.1, 1.2)	Evaluate and compare emissions and economic performance of the latest technologies being considered for carbon capture and sequestration.
2.	Carbon Tax Breakpoint Analysis for greenfield projects	Cost of Electricity with various Carbon Tax levels. Break-even Carbon Tax at which utilities would prefer CCS (Figure 1.3, 1.4)	Identify carbon tax crossover points where utilities would be motivated to install CCS technologies.
3.	Carbon Tax Breakpoint Analysis for existing power plants	Cost of Electricity with increasing Carbon Tax levels. Break-even Carbon Tax at which utilities would prefer CCS (Figure 1.5)	Identify carbon tax crossover points where utilities would be motivated to install CCS technologies.
4.	Carbon Tax Breakpoint Analysis with potential revenue from captured CO ₂	Revenue from CO ₂ Utilization versus carbon tax breakpoint. (Figure 1.6)	Explore the prospects of revenue from CO ₂ on carbon tax breakpoint.
5.	Price Shock Analysis: variation of coal price	Projected cost of electricity as coal price increases. (Figure 1.7)	Determine the sensitivity of each technology to increases in fuel price.

1.5 Results and Discussion

Capturing carbon from coal-fired power plants is an energy intensive process increasing both capital and operating expenses compared to power-plants of equivalent net output without carbon capture. With more stringent regulations on emissions and potential carbon legislation expected in the future, utilities considering expanding baseload capacity face a myriad of uncertainty regarding which technology will remain

most economical. In the face of these uncertainties, previous studies have focused on whether a new coal plant should be pulverized coal (PC) with amine-based post-capture or integrated gasification and combined cycle (IGCC) (Bergerson and Lave, 2007). Recently, oxy-fuel combustion has been touted as the most economic alternative (Suresh and Reddy, 2011).

1.5.1 Economics of Carbon Capture Technologies

Successful carbon storage and sequestration was first achieved on a commercial scale in the Sleipner West gas field, located in the North Sea off the coast of Norway. Natural gas at this location did not meet the industry specifications as it contained nearly 9% CO₂, exceeding the commercial specifications by 6.5%. To correct the issue, CO₂ was compressed and then injected into the Utsira Formation, an aquifer 800 m below the seabed. Since Norway passed an offshore carbon tax in 1996, the Sleipner West site has been injecting 1 million metric tons of CO₂ into the aquifer annually. Norwegian officials tax approximately \$38 per metric ton of CO₂ emitted into the atmosphere. With an initial investment of \$80 million, Statoil, the company operating the site, was able to realize a full payback on its investment in 1.5 years. This is a well-documented example of how a government-imposed price on carbon can dramatically alter the economic feasibility of CO₂ sequestration (Herzog, 2004).

Geological sequestration in deep saline aquifers (DSAs) offers several attractive characteristics, potentially making them ideal locations for CO₂ storage. Composed primarily of highly mineralized brines, these deep saline aquifers are relatively plentiful and offer theoretical storage capacities that dramatically exceed those of similar sequestration techniques. These very large volumes have more than enough capacity, if fully realized, to significantly reduce the anthropogenic emissions of CO₂ into the atmosphere. In their current state, deep saline aquifers offer little or no economic value to humans. The water is so highly mineralized that it would be nearly impossible for future generations to turn to DSAs as a source of water or minerals. DSAs occur at the depths necessary (usually around 800 m) to achieve the appropriate temperatures and pressures that ensure CO₂ remains in the liquid or supercritical state. In the United States, deep saline aquifers are widely dispersed, and offer significant storage capacity

for large-scale implementation of CCS. However, there is no financial gain from this sequestration method without regulatory pricing of carbon (Bergerson and Lave, 2007).

The majority of coal-fired power plants in the U.S are subcritical units. The overall net efficiency of power plants increases as pressures and temperatures rise until supercritical or ultra-supercritical (USC) conditions are reached in the boiler. However, reaching these conditions increases the capital expenditure, increasing required revenue necessary for 10% return on investment, and thus the cost of electricity. Carbon capture technologies were compared via the financial baseline parameters found in Table 1.2. Values are based on a greenfield analysis; that is calculations assume there is no equipment in place or in use and the entire facility is constructed new. Simulations are also performed for existing coal-fired power plants.

Previous studies demonstrate as capacity of a power plant increases, the unit cost of electricity decreases due to economies of scale (Rubin et al., 2004). Preliminary analysis indicates this relationship holds when implementing CCS. The purpose of this analysis is to differentiate the economic impacts of the various CCS options currently considered for large-scale deployment. To assist in comparing existing literature, a net electric output of approximately 500 MW was used in this analysis.

Primary outputs can be found in Table 1.4. As seen in the table, new subcritical plants with the latest environmental controls operate at higher net plant efficiency than any carbon capture scenario simulated. Among CCS technologies at subcritical conditions, oxy-coal and IGCC perform with similar efficiencies at just over 26%, a 23% drop from PC plants with no capture. However, when operating at ultra-supercritical conditions, oxy-coal performs with the greatest net plant efficiency at nearly 32.73%. Compared to the net plant efficiency of conventional coal-fired power plants, 40.84%, oxy-coal with CCS represents a 25% reduction in efficiency while eliminating 90% of CO₂ emissions.

Table 1.4: Summary of results for four CCS technologies. Fuel used is PRB priced at \$8.75/ton as fired, all plants have a capacity factor of 75%.

Parameter	PC - Subcritical			PC - Supercritical			PC - Ultra-Supercritical			IGCC	
	Reference	Amine	Oxy	Reference	Amine	Oxy	Reference	Amine	Oxy	Reference	with Capture
Gross Plant Size (MW)	540	690	750	540	670	730	535	645	702	995	980
Net Plant Output (MW)	500	504	501	503	504	501	501	503	501	583	498
Net Plant Efficiency, HHV (%)	34.78	19.47	26.36	36.99	21.7	28.68	40.84	25.5	32.73	31.5	26.46
Net Plant Heat Rate, HHV (Btu/kWh)	9,810	17,530	12,950	9,225	15,730	11,900	8,355	13,380	10,430	10,830	12,900
CO ₂ Capture System	None	Amine	Oxy-fuel	None	Amine	Oxy-fuel	None	Amine	Oxy-fuel	None	GE Selexol
Air-Separation Cost/CO ₂ Capture Cost (Total Levelized Annual Cost) (M\$/yr)	N/A	190	197	N/A	175	173	N/A	147	159	N/A	66
Carbon Capture Capital Required (M\$)	N/A	683	869	N/A	634	720	N/A	515	666	N/A	384
Environmental Controls Capital Required (M\$)	180	259	150	175	244	144	165	222	135	122	114
Base Plant (M\$)	687	1,003	886	734	1,036	928	778	1,051	961	1,090	1,097
Total Capital Requirement (M\$)	866	1,945	1,905	909	1,914	1,792	943	1,789	1,762	1,212	1,595
Cost of electricity (\$/MWh)	45.27	114.70	100.60	46.34	110.30	94.41	47.18	101.10	91.19	53.89	90.45

Without capture technology, the significantly more complex processes involved in IGCC operations increase the capital required to invest in a new IGCC plant over a traditional PC plant: approximately \$1,212M to \$866M respectively. Among CCS technologies, post-capture with amine sorbents represents the most capital-intensive technology costing \$1,945M, and IGCC-CCS would be the least capital-intensive project costing \$1,595M. This indicates that it would be less expensive, in terms of initial capital required, to enter a carbon-constrained world by investing in IGCC plants. However, if a utility is operating a PC plant, as are the majority, it is evident that a transition to oxy-coal would be more economically attractive than implementing amine-based capture.

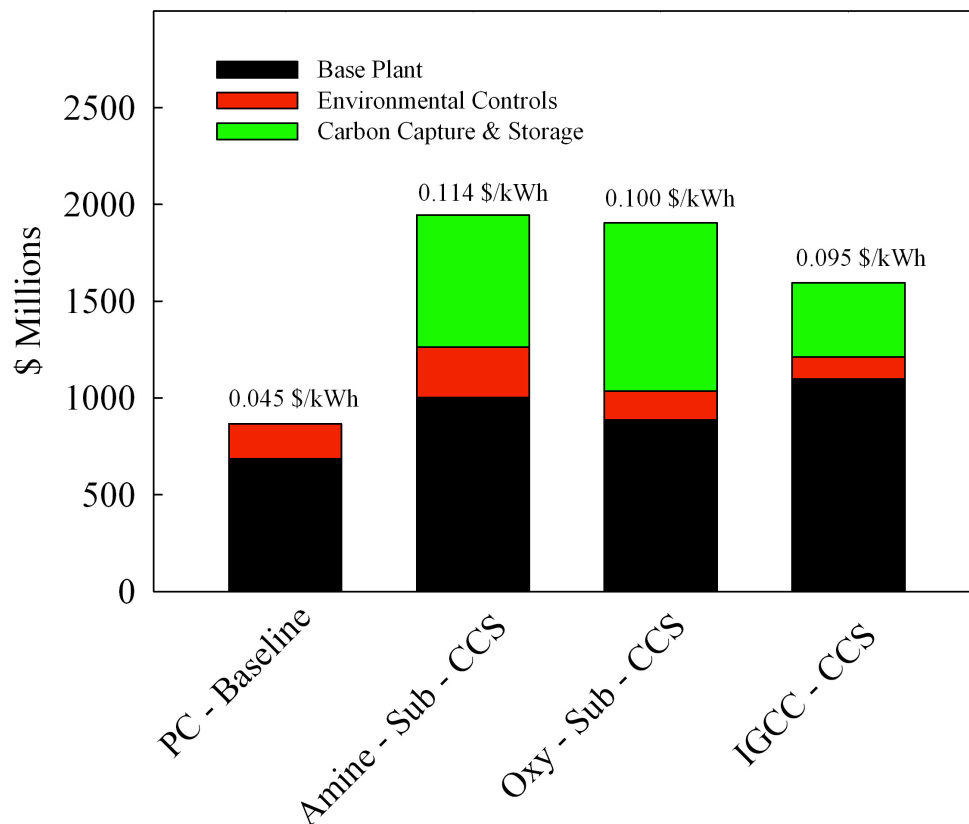


Figure 1.1: Capital required for new 500 MW-net power plants. Capital expenses are separated into the following sections of operation: Black - Base plant equipment (such as boiler, steam turbines); Red - Environmental controls (SO_x, NO_x, PM, Hg); Green – Carbon capture & storage for subcritical PC power plants.

The revenue required per megawatt hour (MWh), or minimum cost of electricity (COE), the utility must charge to recover all expenditures in capital, goods, and services, is also shown in Table 1.4. Again, among capture technologies, IGCC provides a slightly lower COE compared to oxy-coal under USC conditions: 90.45 to 91.19 (\$/MWh). However, IGCC with CCS requires significantly more gross power to provide equivalent MW-net output due to operational power needs (i.e. power block, air compressor, air separation unit).

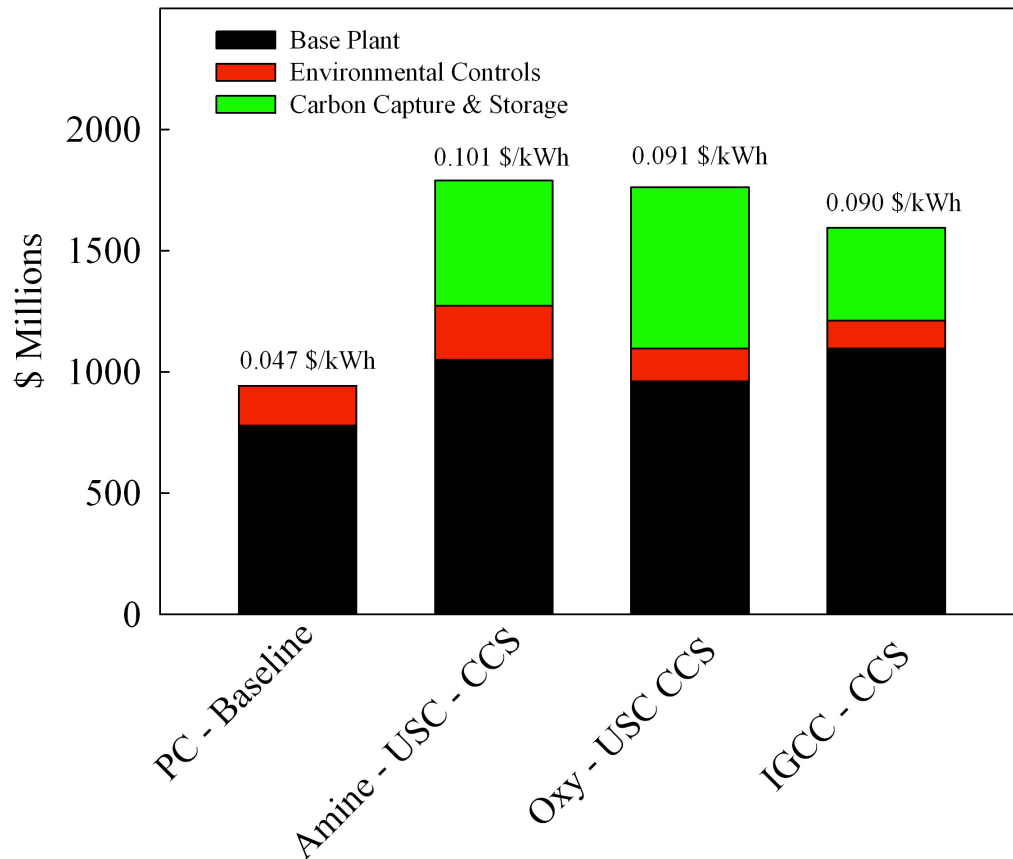


Figure 1.2: Capital required for new 500 MW-net power plants. Required revenue is displayed above the plot for each technology. Capital expenses are separated into the following sections of operation: Black - Base plant equipment (such as boiler, steam turbines); Red - Environmental controls (SO_x, NO_x, PM, Hg); Green – Carbon capture & storage for Ultra-supercritical PC Plants.

1.5.2 Carbon Tax Breakpoints for Greenfield Projects

The effect of a carbon tax on a utility's decision to implement CCS was examined. A flat carbon tax is gradually introduced into the model and the results are illustrated in figures 1.3 and 1.4. The carbon tax break point is the dollar value placed on CO₂ emissions (per ton) at which a utility would find it more economical to install CCS rather than pay the tax. Figure 1.3 displays the relationship between cost of electricity and the value of the carbon tax with CCS technologies for coal plants operated at subcritical conditions. This illustrates the effect of a carbon tax on the revenue required by the utility to recuperate their investment.

The carbon tax breakpoint for a conventional subcritical power plant with amine-based CCS is \$81/ton of CO₂ compared to one without CCS. When comparing the two scenarios at ultra-supercritical conditions, the carbon tax breakpoint drops to \$72/ton. However, when comparing an ultra-supercritical PC plant with amine-based capture to a subcritical PC plant without capture, the carbon tax breakpoint is 62\$/ton. The carbon tax breakpoint for a subcritical oxy-coal plant with CCS is \$60/ton when compared to a conventional subcritical PC plant without capture. Again, comparing the two scenarios at ultra-supercritical conditions as represented in figure 1.4, the carbon tax breakpoint drops to \$57/ton. The carbon tax breakpoint for an ultra-supercritical oxy-coal plant with CCS is \$49/ton when compared to a conventional subcritical PC plant without capture. If a utility is operating IGCC, a carbon tax of \$35/ton of CO₂ provides economical justification for adding CCS. IGCC with CCS has a carbon tax breakpoint of \$48/ton compared to a subcritical PC plant.

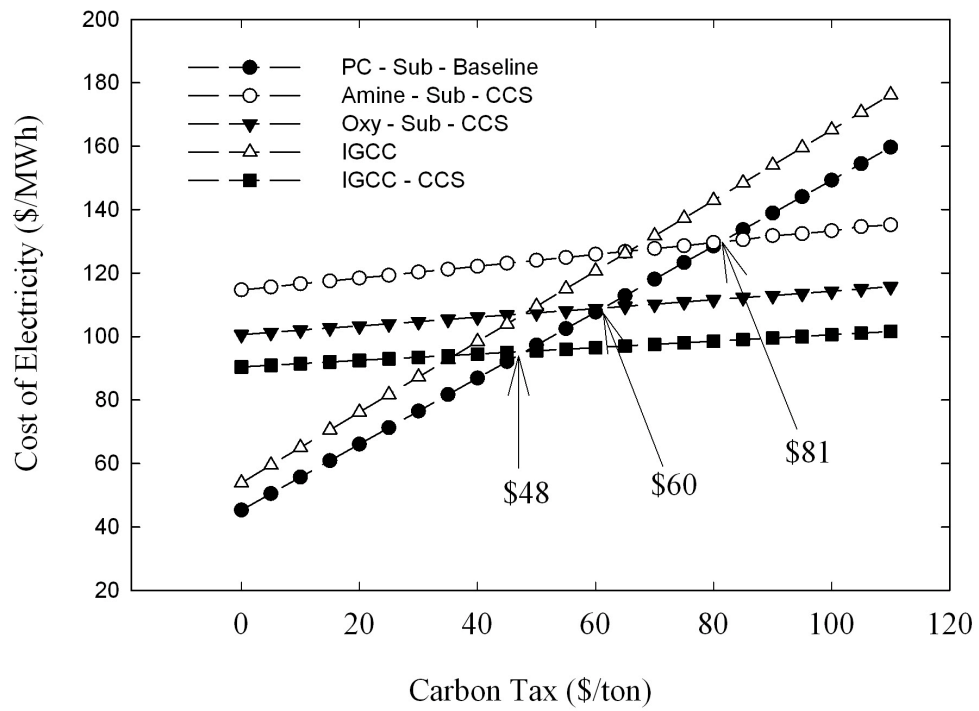


Figure 1.3: Carbon tax breakpoint analysis for greenfield plants: (—●—) PC – Baseline; (—○—) Amine – CCS; (—▼—) Oxy-coal – CCS; (—△—) IGCC; (—■—) IGCC – CCS: Subcritical PC plants with CCS – 500 MW-net.

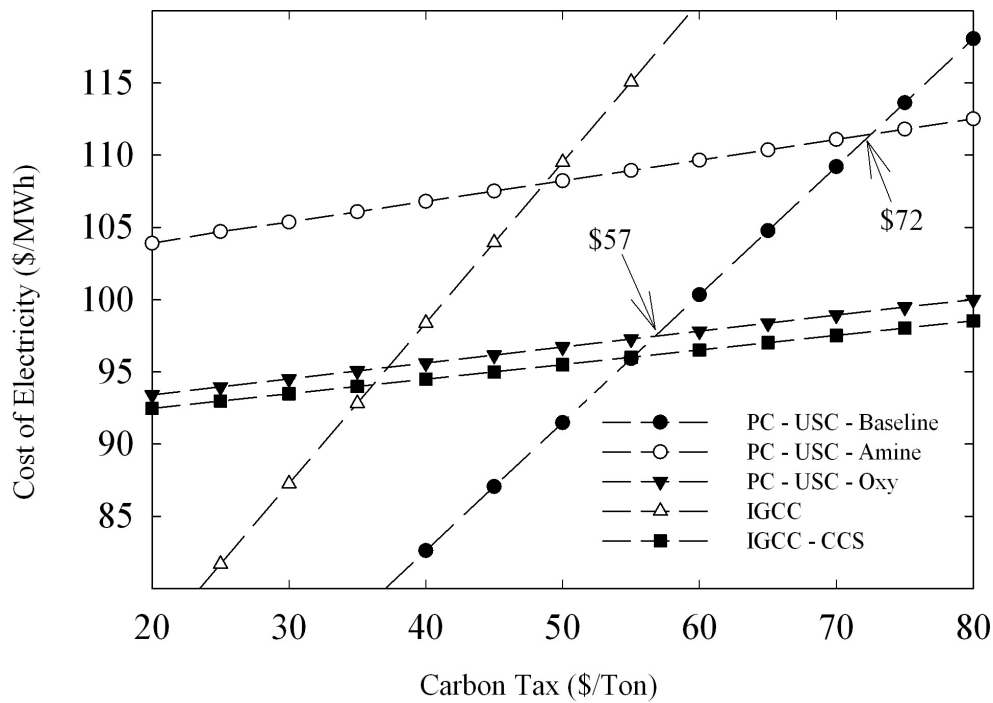


Figure 1.4: Carbon tax breakpoint analysis for greenfield plants: (—●—) PC – Baseline; (—○—) Amine – CCS; (—▼—) Oxy-coal – CCS; (—△—) IGCC; (—■—) IGCC – CCS: Ultra-supercritical PC Plants with CCS – 500 MW-net.

The actual choice of utilities may hinge on factors beyond the scope of this analysis including: inherent uncertainty in the construction cost of new projects, differences in state regulations, community and political considerations, or investment in research and development. Investment efficiency should also be considered when determining the most financially attractive venture. As seen in Figure 1.2, a higher capital cost does not necessarily indicate lower investment efficiency. Comparing PC and IGCC without CCS, it is clear that IGCC plants are more capital intensive. However, improvements in the efficient utilization of the fuel stock offset the added initial capital investment, making IGCC competitive with PC plants today, though the inevitability of increased down time as systems become more complex dictates there is more risk involved.

1.5.3 Carbon Tax Breakpoints for Existing Power Plants

The U.S. coal-fired power plant fleet is mature, with a capacity-weighted mean age of 34 years and many units well past their originally planned useful lives. The situation in the European Union is similar with 50% of coal-fired power plants in operation for more than 30 years. When faced with a carbon constrained world, utilities will consider the prospect of retrofitting existing power plants with carbon capture technologies, or retiring old plants to build new ones. When retrofitting old plants, new carbon capture equipment installed at existing facilities may face a shortened operating life, and therefore capitalized using a shorter useful life. The remaining useful life (RUL) of a power plant is a somewhat hypothetical value, as utilities often replace major components extending the useful life of the plant. However, in this paper, the analysis is conducted assuming a RUL for a period without additional capital investment. Figure 1.5 simulates this scenario for oxy-coal and amine capture technologies operated at subcritical conditions to better approximate retrofitting existing plants. Power plants were modeled at 500 MW-net capacities with remaining useful lives of 10 and 20 years.

Oxy-coal provides a lower cost of electricity in both scenarios. The carbon tax breakpoint for oxy-coal capture with an RUL of 20 years is approximately \$75/ton CO₂, and \$95/ton CO₂ for an RUL of 10 years. Amine capture becomes economically attractive at a carbon tax of \$92/ton CO₂ when the RUL is 20 years, and \$113/ton CO₂ for an RUL of 10 years. For existing plants, the addition of carbon capture technology is economically beneficial at a higher carbon tax than for a greenfield project. According to this analysis, a carbon tax lower than \$75/ton would not be sufficient to encourage retrofitting a significant portion of the existing coal-fired power plant fleet.

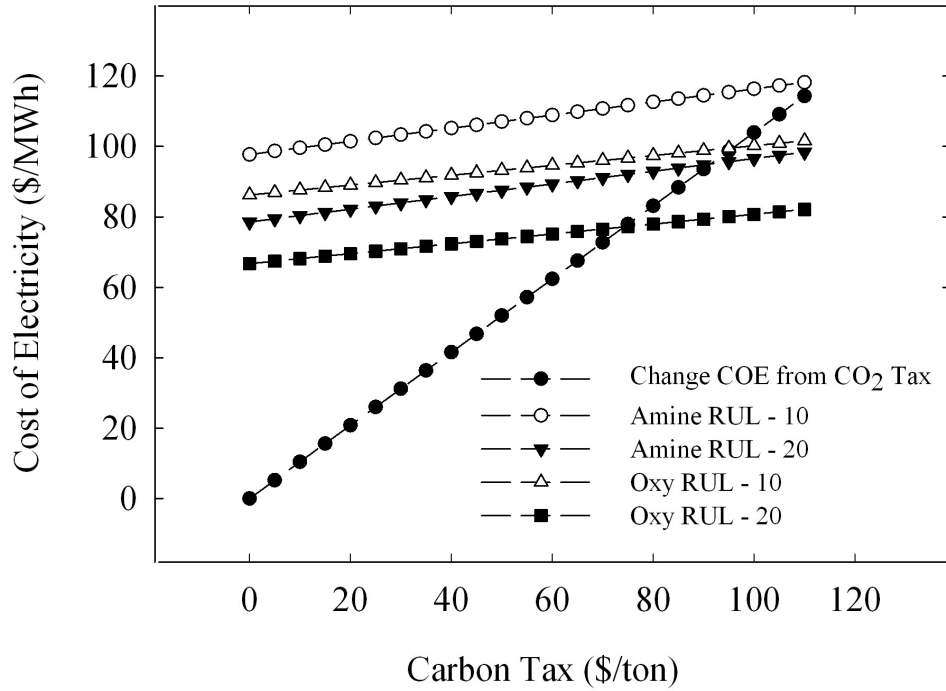


Figure 1.5: Carbon tax breakpoint analysis for existing subcritical plants: (—●—) Change in cost of electricity from CO₂ Tax; (—○—) Amine – RUL - 10; (—▼—) Amine – RUL - 20; (—△—) Oxy – RUL - 10; (—■—) Oxy – RUL - 20

1.5.4 Economics of Carbon Capture and Utilization

With the likelihood of carbon legislation in the U.S. dwindling, potential markets for captured CO₂ may be pivotal in reducing emissions from coal-fired power plants. Markets for carbon dioxide exist in the food and oil industries. Injection of CO₂ into depleted oil reservoirs provides dual advantages. It allows for enhanced oil recovery by re-pressurizing wells and allowing otherwise uncollectible oil to be extracted. The revenue generated offsets the increased costs associated with CCS by making CO₂ a commodity. Additionally, since these reservoirs have stored oils and gases for millions of years, they have already proven themselves suitable for the long-term containment of CO₂. Unfortunately, the coupling of CCS and enhanced oil recovery requires a level of geographic proximity between the stationary emission sources and a suitable oil field; or the availability of pipeline infrastructure to transport CO₂. Therefore, the majority of

U.S. coal-fired power plants will likely be unable to realize this potential revenue stream from captured CO₂.

Understanding the effect of revenue streams on the economics of CCS will assist policy makers, researchers, and utilities in planning for future electric generation. Several technologies are currently being pursued to generate profitable products from CO₂ streams. The efficiency of photo-catalytic conversion of CO₂ is improving at the laboratory scale. (Wang et al., 2011) Algal conversion of CO₂ and light into biofuels offers yet another avenue for revenue. Establishing profitability targets provides economic benchmarks for scientific researchers looking to generate revenue from CO₂ in a carbon capture and utilization scenario. If carbon legislation continues to be stagnant, potential markets for CO₂ may be the deciding factor in implementing carbon capture. The effect of revenue streams on the carbon tax breakpoint at various ratios of CCU and CCS are analyzed at increasing CO₂ revenue targets.

Figure 1.6 shows the impact of revenue from CO₂ utilization on the carbon tax breakpoint in an oxy-coal plant at ultra-supercritical conditions. Three ratios of CCS to CCU are modeled, all with 90% of CO₂ captured and the remaining 10% emitted into the atmosphere. When utilizing 90% of CO₂ emission at a value of \$12/ton of CO₂, the carbon tax breakpoint drops to \$35/ton of CO₂. When utilizing 10% of the CO₂ and sequestering the remaining 80%, revenue from CO₂ has little impact on the carbon tax breakpoint.

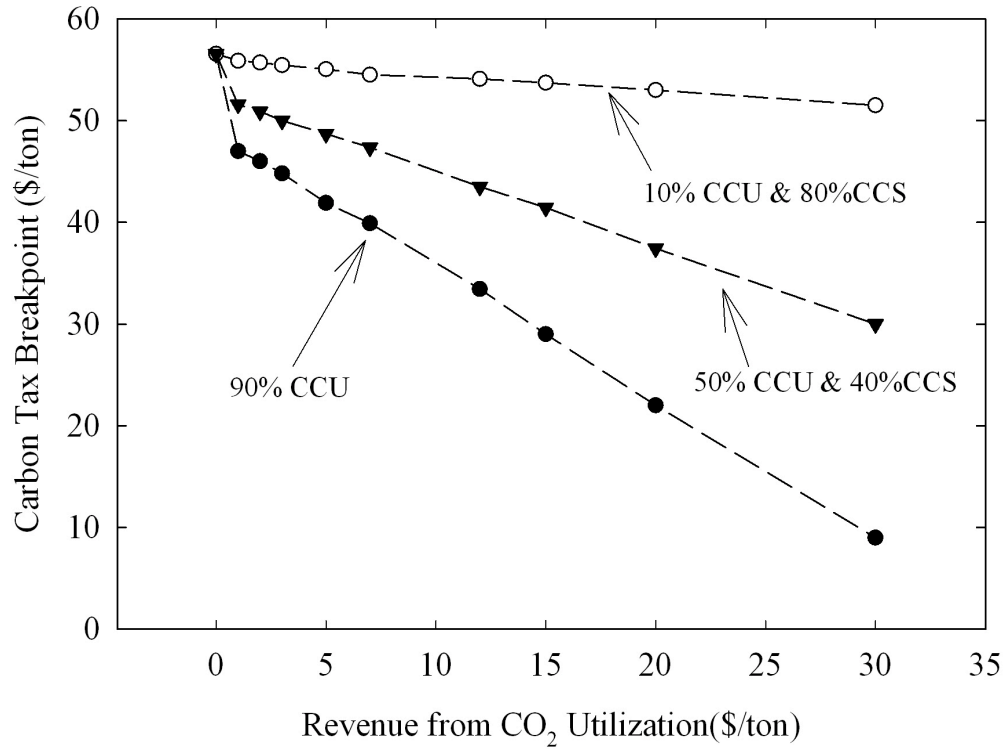


Figure 1.6: Carbon tax breakpoint vs. revenue from CO₂ utilization: Impacts on carbon tax breakpoints from revenue generated via CO₂ utilization from PC-Oxy-USC are shown with 90% CO₂ capture efficiency and three utilization to sequestration ratios; 90% CCU (—•—); 50% CCU and 40% CCS (—▼—); 10% CCU and 80% CCS (—◊—)

1.5.5 Sensitivity to Coal Price - CCS Technologies

As with other fossil fuels, the price of coal varies over time. Oil price increases over the past several decades provides compelling evidence that, as resources become less economically recoverable, fuel prices can rise significantly. Modeling a similar increase in coal prices provides insight into which coal combustion technology is the best long-term investment. The baseline price modeled for this analysis was the \$8.75 USD per short ton of Powder River Basin coal, which accounts for over 40% of US production. In China, due to limitations in the capacity of domestic coal transportation, imports of coal average over \$100 per ton. Figure 1.7 displays the impact of increases in coal prices up to \$500 USD. When implementing carbon capture

and sequestration, oxy-fuel technology is less sensitive to increases in coal price. Of the three commercially deployable CCS processes, oxy-fuel combustion provides the lowest net heating rate under ultra-supercritical conditions. As IGCC has a higher net plant heating rate compared to oxy-coal, it will likely be more sensitive to increases in the price of coal.

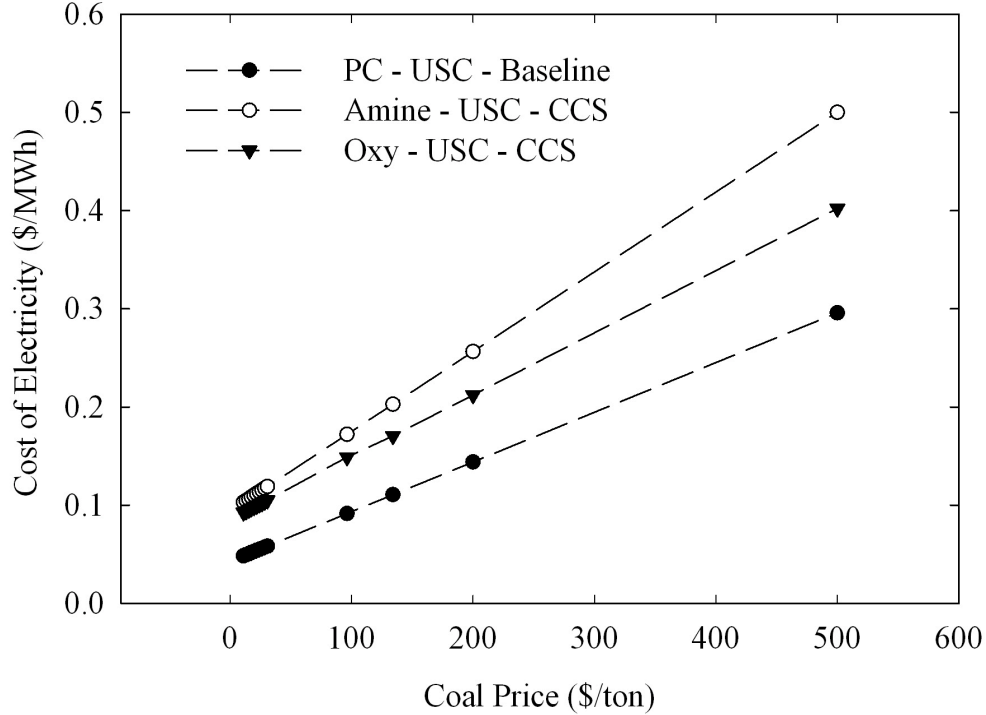


Figure 1.7: Coal price sensitivity – Sensitivity analysis of the PC capture technologies to increasing coal prices. PC - USC - Baseline (—●—); Oxy - USC - CCS (—▼—); Amine - USC - CCS (—○—)

1.6 Conclusions

In the current economic and regulatory climate, conventional PC technology is the least cost alternative for utilizing coal as a fuel stock. However, if carbon legislation emerges, the economics of coal utilization change when prices of CO₂ exceed \$35/ton. If a tax on carbon emissions were enacted today, a value of \$35/ton CO₂ emissions would make IGCC with CCS more attractive than IGCC with no capture. A utility may find it more economical to pay the emissions penalty at any value below that threshold. Oxy-coal combustion operated at ultra-supercritical temperatures and pressures with

carbon capture and sequestration represents the most attractive option for utilities with PC plants. For existing plants, the addition of carbon capture technology will happen at a higher level of carbon tax. According to this analysis, a carbon tax lower than \$75/ton would not provide sufficient economic justification for utilities to retrofit a significant portion of the existing coal-fired power plant fleet.

The notion that coal will remain in use through to the next century is predicated on assumptions that indicate coal as the least expensive method of producing electricity. Coal is abundant, but it may not always be so readily obtained and distributed. Therefore, assuming coal will remain a cheap fuel stock for decades to come may hinder sound investments. Additionally, increasing concerns related to anthropogenic CO₂ emissions indicates a potential for future carbon regulations. The United Nations Framework Convention on Climate Change at the 17th Conference of the Parties forecasted a globally binding treaty as early as 2020. Investors in energy technology will be paying close attention to the results of future negotiations. Further research pertaining to performance targets at planned commercial scale CCS projects will provide greater insight into the economics of advanced combustion technologies for coal utilization.

Chapter 2

Techno-economic Assessment of Advanced Coal Combustion Technologies Suitable for Carbon Capture and Sequestration in India

2.1 Introduction

Economic development has historically come from expanding access to energy. Currently, electricity generation is a primary concern for the Government of India (GoI) as demand across the country grows. Coal is the primary method of electricity generation in India. With 170 coal-fired power plants cleared for production, and over 700 seeking environmental clearances, coal is currently the fastest way to boost baseload capacity. However, such an expansion of power generation will have significant impacts on water resources and the environment. Additionally, Indian domestic coal resources cannot satisfy the current demand, resulting in increased imports of more expensive coal. Unless major growth in generation capacity from nuclear power or renewable energy occurs in India, coal will remain a significant component of the global energy portfolio. Coal resources in India are considered to be abundant, energy dense, and currently inexpensive. However, maintaining a steady supply of domestic coal has proven to be an issue. Additionally, associated CO₂ emissions and other pollutants remain a concern (Biswas et. al, 2011). Examining technologies suitable for carbon

capture and sequestration will allow decision makers better insight into the economic situation for coal-fired power plants in the emergence of a carbon-constrained future.

The Indian power sector is currently dominated by sub-critical PC units operating with a fleet wide efficiency of 29%, compared to the 32% fleet wide efficiency of the coal fleet in the United States. While preparing for a carbon constrained future, India's policy makers are more focused on improving the efficiency of the coal fleet. However, it is important to analyze the impacts of advanced combustion technologies, ensuring India remains competitive on the global market with state-of-the-art technology.

As discussed in Chapter 1, carbon can be sequestered from coal via three commercially viable processes: post-combustion, pre-combustion, and oxy-combustion technologies. Here, a comparison of these technologies is presented with financial assumptions reflecting the situation in India, one of the largest developing economies of the world. Table 2.1 shows the financial assumptions used in this analysis. Two coal stocks are modeled to determine the benefit of importing more expensive, yet higher quality coal. The composition for the coals used in this analysis can be found in Tables 2.2. and 2.3.

Table 2.1: Financial assumptions for India analysis

Financial Assumptions	
Plant or Project Book Life (years)	30
Real Bond Interest Rate (%)	5.83
Real Preferred Stock Return (%)	0
Real Common Stock Return (%)	8.74
Percent Debt (%)	70
Percent Equity (Preferred Stock)(%)	0
Percent Equity (Common Stock)(%)	30
Inflation (%)	0
Federal Tax Rate(%)	34
State Tax Rate (%)	4.15
Property Tax Rate (%)	2
Investment Tax Credit (%)	0

Table 2.2: Modeled Composition of Indian Coal

Indian Coal	
Heating Value (Kcal/Kg)	3,800
Carbon (wt%)	41.11
Hydrogen (wt%)	2.76
Oxygen (wt%)	9.89
Chlorine (wt%)	0
Sulfur (wt%)	0.41
Nitrogen (wt%)	1.22
Ash (wt%)	38.63
Moisture (wt%)	5.98
Cost (USD/Tonne)	50

Table 2.3: Modeled Composition of Indonesian Coal

Indonesian Coal	
Heating Value (Kcal/Kg)	4,636
Carbon (wt%)	58.96
Hydrogen (wt%)	4.16
Oxygen (wt%)	11.88
Chlorine (wt%)	0
Sulfur (wt%)	0.56
Nitrogen (wt%)	1.02
Ash (wt%)	13.99
Moisture (wt%)	9.43
Cost (USD/Tonne)	83

2.2 Methodology

To account for the performance, emissions, and capital expenses associated with the operation of electric power plants, the Integrated Environmental Control Model (IECM) version 6.2.4. is used. The IECM is a publicly available modeling tool that was developed by Carnegie Mellon University in conjunction with the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL). The IECM has been modified to include various configurations for PC plants, IGCC, and oxy-coal systems incorporating transport and storage costs of carbon dioxide. Recent studies have

validated performance characteristics of oxy-fuel systems generated in the IECM with Aspen Plus software (Khorshidi et al., 2011). As in chapter 1, while the IECM has probabilistic capabilities for modeling uncertainty, a conventional deterministic analysis is used for ease of technology comparison.

2.3 Results and Discussion

India has a carbon credit trading system that is under development. The following analysis reports on various carbon trading value breakpoints. These reported values represent the price placed on carbon that would result in the implementation of carbon capture and sequestration technologies. Oxy-coal combustion and Amine based post-combustion capture technologies are modeled. Integrated gasification and combined cycle power plants were not modeled in this simulation as there are technical challenges involved when using high-ash domestic coal. 600 MW-gross operating conditions were modeled to illustrate the impact of energy penalties on the cost of electricity.

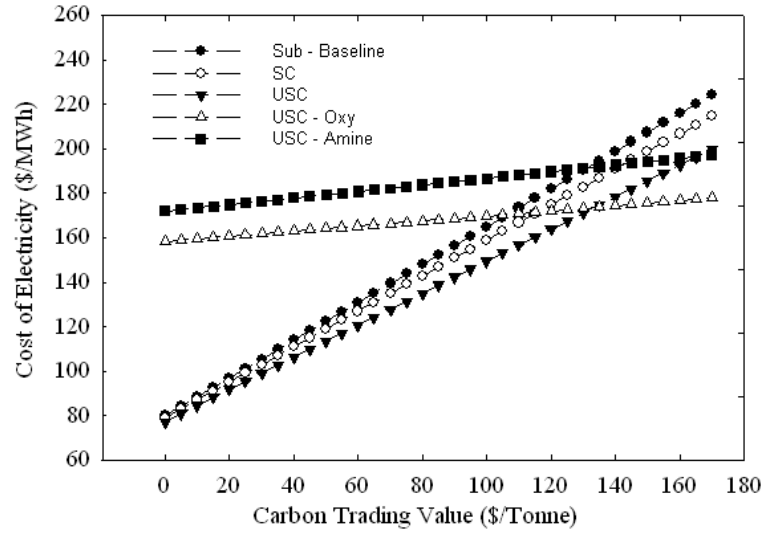


Figure 2.1: Carbon trading value breakpoint analysis for greenfield plants:
 (—◆—) Sub – PC – Baseline; (—○—) SC – PC; (—▼—) USC – PC;
 (—△—) USC – Oxy-coal – CCS; (—■—) USC – Amine – CCS:
 Pulverized Coal Plants with CCS – 600 MW-gross burning Indonesian Coal.

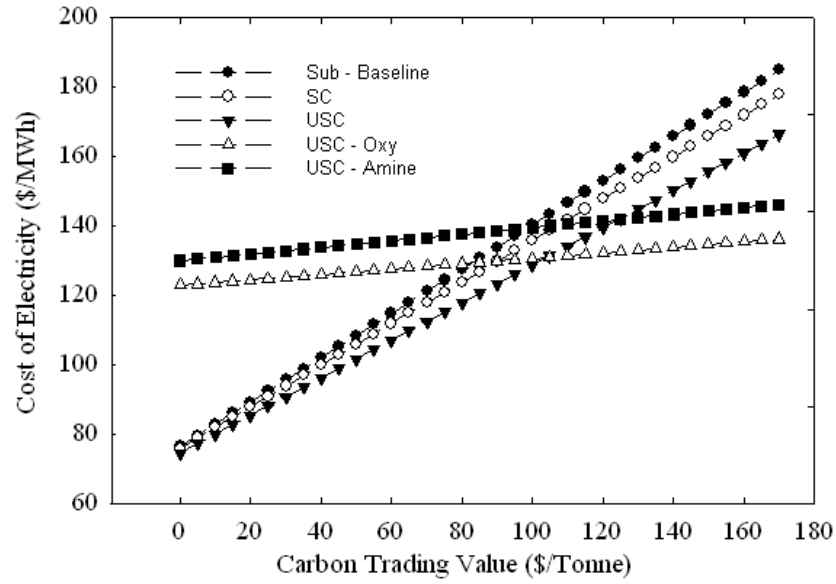


Figure 2.2: Carbon trading value breakpoint analysis for greenfield plants: (—●—) Sub – PC – Baseline; (—◇—) SC – PC; (—▼—) USC – PC; (—△—) USC – Oxy-coal – CCS; (—■—) USC – Amine – CCS: Pulverized Coal Plants with CCS – 600 MW-gross burning Indian Coal.

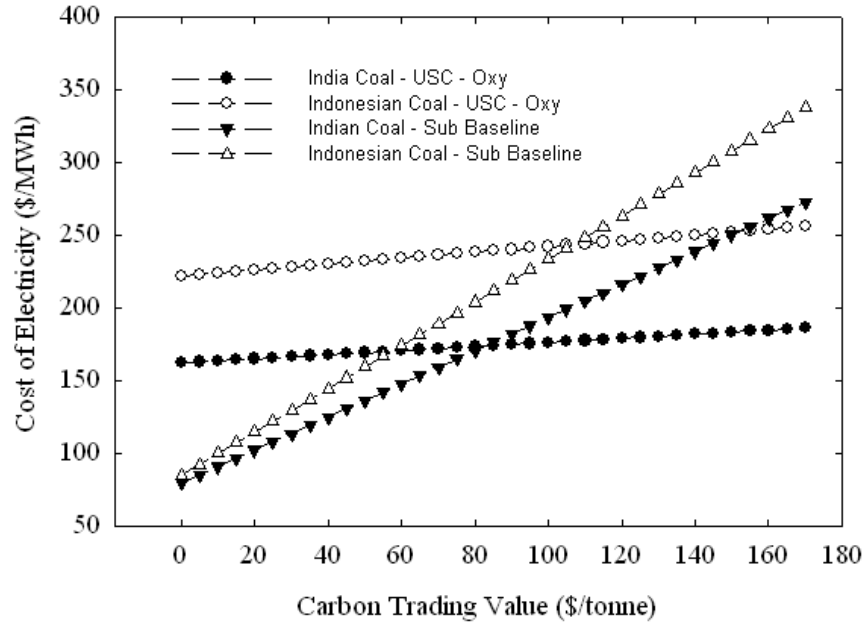


Figure 2.3: Carbon trading value breakpoint analysis for greenfield plants: (—●—) Indian Coal – USC - Oxy; (—◇—) Indonesian Coal – USC – Oxy; (—▼—) Indian Coal – Subcritical Baseline; (—△—) Indonesian Coal – Subcritical – Oxy: Pulverized Coal Plants with CCS – 600 MW-gross

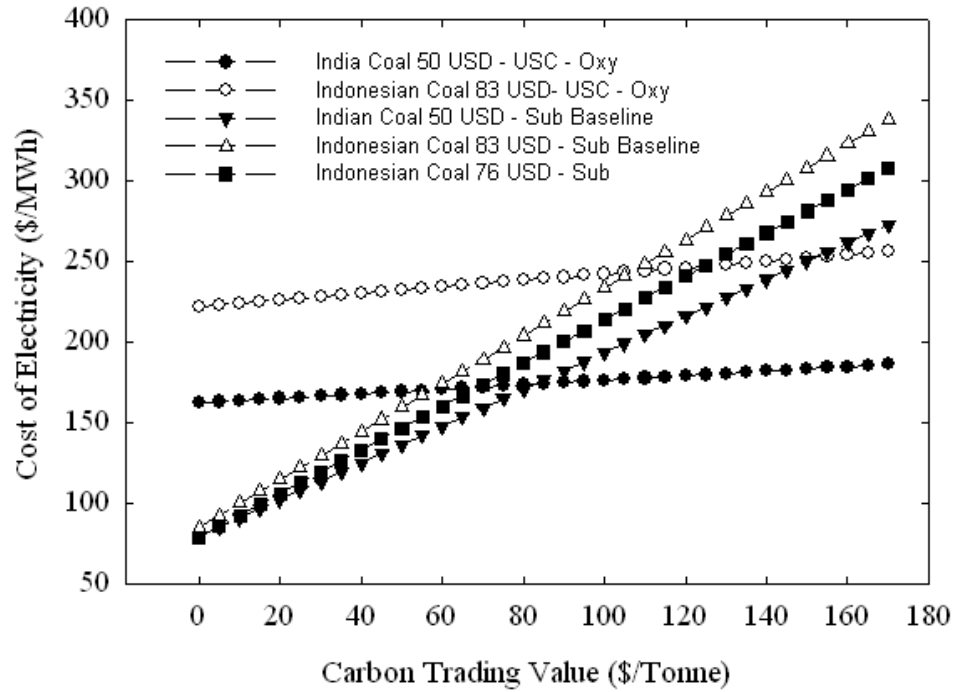


Figure 2.4: Carbon trading value breakpoint analysis for greenfield plants:
 (—●—) Indian Coal – 50 USD – USC - Oxy; (—○—) Indonesian Coal – 83 USD – Ultra-supercritical – Oxy; (—▼—) Indian Coal – 50 USD – Subcritical Baseline; (—△—) Indonesian Coal 83 USD – Subcritical Baseline; (—■—) Indonesian Coal 76 USD – Subcritical Baseline: Pulverized Coal Plants with CCS – 600 MW-gross

According to the results presented in Figures 2.1, 2.2, 2.3, and 2.4, the impact of coal quality and price on the carbon tax breakpoint is significant. When an operating utility is burning Indian coal priced at \$50 USD, the carbon trading value at which installing oxy-coal combustion technology at USC conditions is approximately \$85, compared to \$49 for the US case when compared to a conventional PC plant without capture. If the utility were using amine based post-combustion capture technology, the carbon tax breakpoint would increase to approximately \$100 USD. However, it is important to consider that the Government of India regulates the price of electricity, and certain groups, like the agricultural sector, are afforded free electricity. Additionally, there are many cases of hijacking electricity lines which alters the quantity of electricity available for sale. These complications are relevant when determining if coal based centralized electricity generation with carbon capture and sequestration is an appropriate path forward.

2.4 Future Directions

The Department of Energy, Environmental, and Chemical Engineering at Washington University in St. Louis provides access to incredible opportunities and resources focused on addressing challenging energy issues. Working in the Aerosol and Air Quality Research Laboratory, one can incorporate results from state-of-the-art emissions analysis with trans-disciplinary techniques to study the complex relationship between energy, society, economics, and our environment, identifying and seeking out the most potent points of leverage in the system. A system dynamics approach would assist in modeling the complex relationship found in systems with both exogenous and endogenous variables and acting agents.

Highlighting the link between ultra-fine particles and adverse health effects would also be a valuable directive to push forward. Carbon legislation in the United States faces massive hurdles in the form of misinformation campaigns and politicians distracted by their wealthiest constituents. Working to demonstrate the health benefits of advanced combustion technologies may be a more direct approach that will take better traction in the United States.

Future solutions will require global cooperation on a scale not yet known in history. Different cultures brew different perspectives, and this problem will require multifaceted scrutiny and harmony from them all. But these vantage points often stir conflict. And once the human factor has settled into the mental dichotomy of “I’m right and you’re wrong,” it’s extraordinarily challenging to be open to alternate solutions and proposed mental models; even if only slightly different. As a result, international negotiations on climate change have not yet been fruitful. Hopefully, the nations of the world can come together and agree on a path forward that holds in high esteem the complex energy and environmental nexus in which our economic systems directly impact the ecological systems of the Earth. Perhaps then, the nations of the world will act in accordance with an invaluable truth; there is only one planet on which all people live, and all people must become better stewards of the Earth.

Appendix A

India Biomass Power Plant

Banni, on the edge of the Great Rann of Kutch, considered to be India's most extensive grassland, covering over 2497 km², is invaded by the invasive species *Prosopis juliflora*. The weed is spreading rapidly across the grassland posing a threat to the health of livestock and the growth of other vegetation. A thermal power plant project is proposed in attempt to turn a nuisance into a benefit.

The project proposes using *Juliflora* (“Ganda Bawal” / “Babul”) as a primary fuel stock owing to its abundant availability and rapid growth rate. The power plant shall be designed to support a mix of biomass, primarily *Juliflora*, along with the ability to co-fire coal when biomass supplies are insufficient. India has yet to realize the potential energy that can be sustainably harnessed from biomass resources.

Biomass utilization has been explored across the globe and is gaining more traction. Brazil has been leading the way in exploiting biomass for both biofuels and thermal power production. With an extensive sugar and alcohol industrial sector, Brazil processes more than 426.6 million tonnes of sugar cane annually as of 2009. For electricity production, Brazil employs the use of Biomass Integrated Gasification-Gas Turbines with combined cycle steam turbines. In 2002, 619 MW of electric capacity was available. Additionally, agricultural residues are used for biomass electrical generation (Lora et al., 2009).

Introduction

Electricity access is a pivotal component for developing economies. The government of India is planning electrical generation capacity increases of approximately 80,000 MW. India will have to quadruple electric capacity to keep pace with expected demand due to growth. While the majority of new capacity will be generated via conventional fuels like coal, oil, and natural gas, there is great potential for the utilization of biomass. In the state of Gujarat, renewable sources of energy including solar, wind, small scale hydro, and biomass are being heavily pursued.

Primary motivation for biomass utilization stems from the widespread availability of an invasive species, *Prosopis juliflora* (juliflora). The use of juliflora carries multiple benefits. The widespread growth of juliflora contributes to the degradation of agricultural soil. The proposed biomass power plant is expected to provide employment opportunities for local villagers where the biomass is collected and processed. Additionally, increasing demand for rural electrification is driving the need for expanded energy capacity. Current projects under purview by IL&FS total approximately 8,000 MW.

Biomass utilization has long been lobbied for in India by the Ministry of New and Renewable Energy. Unfortunately, a lack of thorough evaluation of fuel, water, and land use has led to hindered implementation. It is therefore necessary to carefully analyze the project requirements, available alternatives, and the expected impacts of the planned power plant.

In this analysis, a 12 MW biomass power plant, based in Kutch, Gujarat, is analyzed evaluating fuel source, emissions, ash disbursement, water usage, and economic considerations. The power plant will be designed to fire imported coal in the event that biomass is unavailable. Data for analysis will be sourced by the IL&FS Energy, the subsidiary of the Infrastructure Leasing and Financial Services that directs power plant projects. A field visit was conducted to further clarify project details and collect information.

Proposed Biomass Power Plant

The power plant project will be designed to utilize various sources of biomass based on availability. Currently, juliflora is intended as the primary fuel stock with mixed ratios of cotton and castor waste. Imported coal will make up additional energy requirements. The power plant process depicted in Figure 1 is detailed in the following sections.

Biomass fuel is first transferred to a feeding silo where it is stored before being sent into the steam generator via a conveyor belt. The steam generator is a conventional traveling grate steam generator. Heat generated via biomass combustion is used to convert superheated water at 150 °C to steam at 480 °C. The combusted biomass leaves behind a significant amount of bottom ash while generating fly ash in the flue gas. The bottom ash is stored in a silo while the fly ash is trapped in an electrostatic precipitator (ESP).

The steam generated inside the steam generator is sent into a super heater which further heats the steam from 480 °C to 515 °C. This superheated steam is sent into a multistage steam turbine where the steam is gradually expanded to generate power. Some steam is condensed in the steam turbine, this condensed steam is sent to the deaerator. Considering the scarcity of water in the region, low pressure steam out of the turbine is sent to an air cooled condenser, where the steam is condensed. Air is pulled inside the air cooled condenser through a steam ejector. Some steam is lost inside the air cooled condenser requiring make up water. The condensed water is pumped to the deaerator through two centrifugal pumps where the water is deaerated and heated. The heated water is then sent through an economizer which further heats the water before it is sent back into the boiler through a boiler feed pump.

The primary objectives of this analysis are: 1.) to provide a complete mass and energy balance on the biomass project, 2.) provide a dynamic Excel spreadsheet allowing a user to select a specific biomass combination, and 3.) develop a FLASH based module to summarize the analysis on the internet. All objectives have been met. The FLASH module can be found on the Aerosol & Air Quality Research Laboratory website (www.aerosols.wustl.edu/aaqrl/).



Appendix B

Methods and Scripts

Python Script For Parsing Data

```
import sys

import os

prefix = sys.argv[-1]
print 'looking at files starting with %s' % prefix

vals = []

for fname in os.listdir('.'):
    if fname.startswith(prefix):
        tab = None
        idv = fname.split('_')[-1].split('.')[0]
        idv = idv.replace("%'", "")
        idv = int(idv)
        print idv

        for line in open(fname):
            if line.startswith("Tab 'Cost Summary':"):
                tab = 'cost'
            if line.startswith("Total:") and tab=='cost':

                _, _, Myr, mwh = line.split('\t')

                mwh = mwh.rstrip('\n')

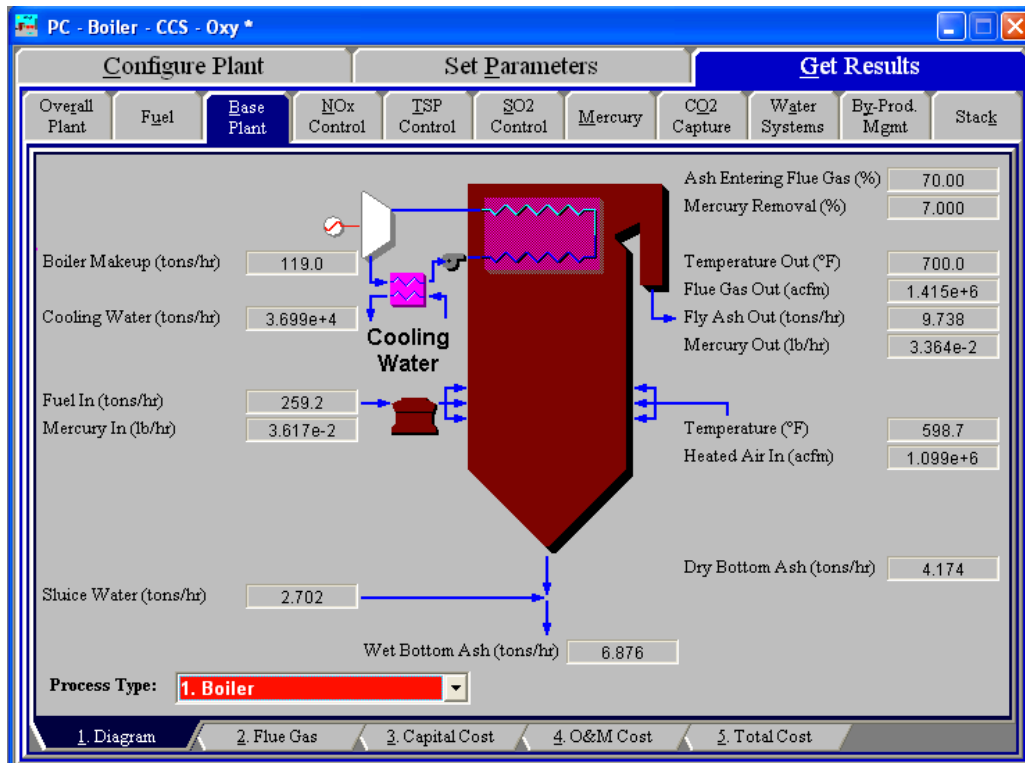
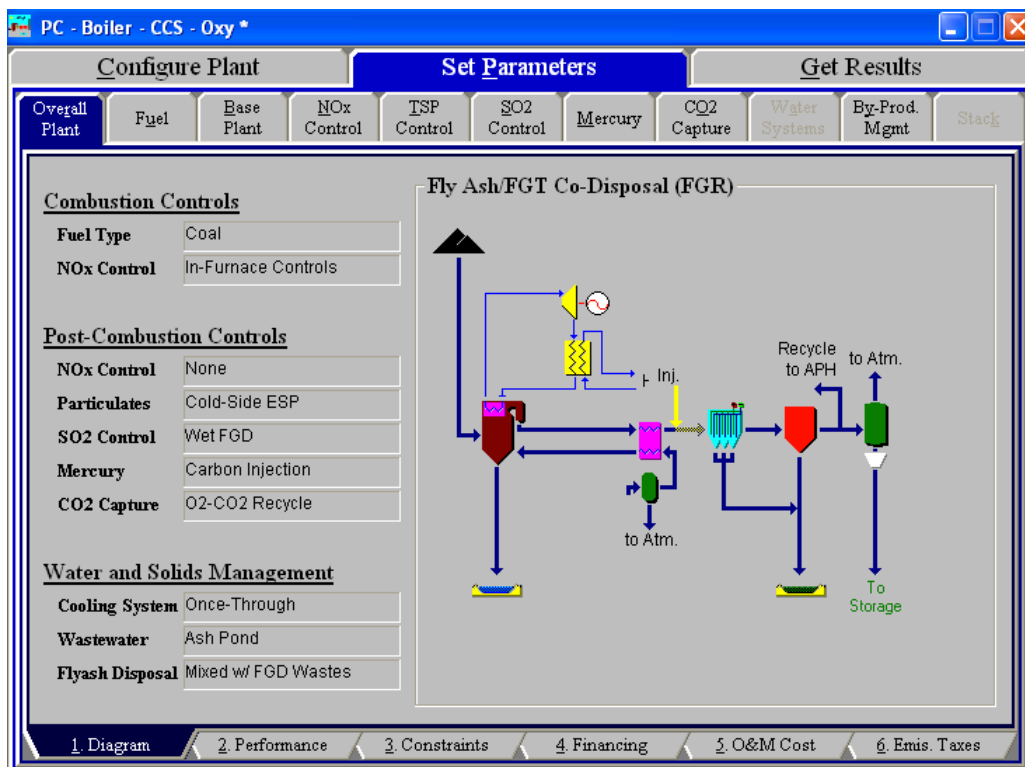
                vals.append( (idv, Myr, mwh) )

            if line.startswith("Tab 'Diagram':"):
                tab = None

vals.sort()

print 'idv\tM/yr\tmwh'
for idv, Myr, mwh in vals:
    print '%s\t%s\t%s' % (idv, Myr, mwh)
```

Screen Shots from IECM Simulations



References

- [1] Bergerson, JA, and LB Lave. 2005. “Should We Transport Coal, Gas, or Electricity: Cost, Efficiency, and Environmental Implications.” *Environmental Science & Technology* 39 (16): 5905–5910.
- [2] Bergerson, JA, and LB Lave. 2007. “Baseload Coal Investment Decisions Under Uncertain Carbon Legislation.” *Environmental Science & Technology* 41 (10): 3431–3436.
- [3] Biswas, Pratim, Wei-Ning Wang, and Woo-Jin An. 2011. “The Energy-Environment Nexus: Aerosol Science and Technology Enabling Solutions.” *Frontiers of Environmental Science & Engineering in China* 5 (3) (July 22): 299–312. doi:10.1007/s11783-011-0351-1.
- [4] Davison, J. 2007. “Performance and Costs of Power Plants with Capture and Storage of CO₂.” *Energy* 32 (7): 1163–1176.
- [5] Descamps, C, C Bouallou, and M Kanniche. 2008. “Efficiency of an Integrated Gasification Combined Cycle (IGCC) Power Plant Including CO₂ Removal.” *Energy* 33 (6): 874–881.
- [6] Heinberg, R, and D Fridley. 2010. “The End of Cheap Coal.” *Nature* 468 (7322): 367–369.
- [7] Herzog, H. 2004. “Carbon Capture and Storage From Fossil Fuel Use.” *Encyclopedia of Energy*.
- [8] Katzer, JR. 2008. “The Future of Coal-Based Power Generation.” *Chemical Engineering Progress* 104 (3): 15.
- [9] Kanniche, Mohamed, René Gros-Bonnivard, Philippe Jaud, Jose Valle-Marcos, Jean-Marc Amann, and Chakib Bouallou. 2010. “Pre-Combustion, Post-Combustion and Oxy-Combustion in Thermal Power Plant for CO₂ Capture.” *Applied Thermal Engineering* 30 (1): 53–62. doi:10.1016/j.applthermaleng.2009.05.005.
- [10] Khorshidi, Z, M Soltanieh, Y Saboohi, and M Arab. 2011. “Economic Feasibility of CO₂ Capture From Oxy-Fuel Power Plants Considering Enhanced Oil Recovery Revenues.” *Energy Procedia* 4 (C) (March 28): 1886–1892. doi:10.1016/j.egypro.2011.02.067.
- [11] McDonald, DK, TJ Flynn, DJ DeVault, R Varagani, S Levesque, and W Castor. 2008. “30 MWt Clean Environment Development Oxy-Coal Combustion Test Program.” 33rd International Coal Utilization and Fuel Systems Conference.

- [12] Herzog, H. 2004. "Carbon Capture and Storage From Fossil Fuel Use." *Encyclopedia of Energy*.
- [13] Katzer, JR. 2008. "The Future of Coal-Based Power Generation." *Chemical Engineering Progress* 104 (3): 15.
- [14] Kanniche, Mohamed, René Gros-Bonnivard, Philippe Jaud, Jose Valle-Marcos, Jean-Marc Amann, and Chakib Bouallou. 2010. "Pre-Combustion, Post-Combustion and Oxy-Combustion in Thermal Power Plant for CO₂ Capture." *Applied Thermal Engineering* 30 (1): 53–62. doi:10.1016/j.applthermaleng.2009.05.005.
- [15] Khorshidi, Z, M Soltanieh, Y Saboohi, and M Arab. 2011. "Economic Feasibility of CO₂ Capture From Oxy-Fuel Power Plants Considering Enhanced Oil Recovery Revenues." *Energy Procedia* 4 (C) (March 28): 1886–1892. doi:10.1016/j.egypro.2011.02.067.
- [16] Lora, E.S., Andrade, R.V., 2009. "Biomass as energy source in Brazil." *Renewable and Sustainable Energy Reviews* 13 (2009): 777–788. doi:10.1016/j.rser.2007.12.004
- [17] McDonald, DK, TJ Flynn, DJ DeVault, R Varagani, S Levesque, and W Castor. 2008. "30 MWt Clean Environment Development Oxy-Coal Combustion Test Program." 33rd International Coal Utilization and Fuel Systems Conference.
- [18] Parsons, JE, AD Ellerman, and S Feilhauer. 2009. "Designing a US Market for CO₂." *Journal of Applied Corporate Finance* 21 (1): 79–86.
- [19] Patiño-Echeverri, D, B Morel, J Apt, and C Chen. 2007. "Should a Coal-Fired Power Plant Be Replaced or Retrofitted?." *Environmental Science & Technology* 41 (23): 7980–7986.
- [20] Rao, AB, and ES Rubin. 2002. "A Technical, Economic, and Environmental Assessment of Amine-Based CO₂ Capture Technology for Power Plant Greenhouse Gas Control." *Environmental Science & Technology* 36 (20): 4467–4475.
- [21] Reinelt, P.S., and D.W. Keith. 2007. "Carbon Capture Retrofits and the Cost of Regulatory Uncertainty." *The Energy Journal* 28 (4): 101.
- [22] Rubin, ES, MR Taylor, S Yeh, and DA Hounshell. 2004. "Learning Curves for Environmental Technology and Their Importance for Climate Policy Analysis." *Energy* 29 (9-10): 1551–1559.
- [23] Rubin, E.S., Berkenpas, M.B. 2009 User Documentation: Integrated Environmental Control Model (IECM) with Carbon Capture and Storage (CCS). Prepared by Carnegie Mellon University for National Energy Technology Laboratory, Pittsburgh, PA.

- [24] Sekar, RC, JE Parsons, HJ Herzog, and HD Jacoby. 2007. "Future Carbon Regulations and Current Investments in Alternative Coal-Fired Power Plant Technologies." *Energy Policy* 35 (2): 1064–1074.
- [25] Sturm, E, and DK McDonald. 2011. "FutureGen 2.0: Oxy-Coal'S Opportunity."
- [26] Suresh, M, and K Reddy. 2011. "Thermodynamic Optimization of Advanced Steam Power Plants Retrofitted for Oxy-Coal Combustion." *Engineering for Gas Turbines and Power*.
- [27] Suriyawong, Achariya, Christopher J Hogan Jr., Jingkun Jiang, and Pratim Biswas. 2008. "Charged Fraction and Electrostatic Collection of Ultrafine and Submicrometer Particles Formed During O₂– CO₂ Coal Combustion." *Fuel* 87 (6) (May): 673–682. doi:10.1016/j.fuel.2007.07.024.
- [28] Varagani, RK, F Châtel-Pélage, P Pranda, M Rostam-Abadi, Y Lu, and AC Bose. 2005. "Performance Simulation and Cost Assessment of Oxy-Combustion Process for CO₂ Capture From Coal-Fired Power Plants." The 4th Annual Conference on Carbon Sequestration, Alexandria, VA, USA.
- [29] Wall, Terry, Rohan Stanger, and Stanley Santos. 2011. "Demonstrations of Coal-Fired Oxy-Fuel Technology for Carbon Capture and Storage and Issues with Commercial Deployment." *International Journal of Greenhouse Gas Control* 5 (July 1): S5–S15. doi:10.1016/j.ijggc.2011.03.014.
- [30] Wang, Wei-Ning, Jinho Park, and Pratim Biswas. 2011. "Rapid Synthesis of Nanostructured Cu–TiO₂–SiO₂ Composites for CO₂ Photoreduction by Evaporation Driven Self-Assembly." *Catalysis Science & Technology* 1 (4): 593. doi: 10.1039/c0cy00091d.

Vita

Craig Bryan Jacobson

Date of Birth	October 16, 1983
Place of Birth	Saint Louis, Missouri
Degrees	B.S. General Engineering, UIUC, May 2006 M.E. Energy, Environmental & Chemical Engineering, May 2010 M.S. Energy, Environmental & Chemical Engineering, August 2012
Publications	Sahu, M., Wu, B., Zhu, L., Jacobson, C.B., Wang, W.-N., Jones, K., Goyal, Y., et al. (2011a). Role of dopant concentration, crystal phase and particle size on microbial inactivation of Cu-doped TiO ₂ . <i>Nanotechnology</i> , 22(41), 415704. doi: 10.1088/0957-4484/22/41/415704 Jacobson, C.B., Biswas, P. (2012) Economic Prospects for Advanced Coal Combustion Technologies with Carbon Capture, Sequestration and Utilization, <i>The Energy Journal</i> , (Submitted)

Economic CCS_Jacobson, M.S. 2012